DISTRIBUTED GENERATION
CONCLUSIONS AND RECOMMENDATIONS

Maine Public Utilities Commission
Final Report to the Maine Legislature

October, 2001

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I. EXECUTIVE SUMMARY

A. Background

This report is the response of the Maine Public Utilities Commission (Commission) to a legislative directive that we study the potential impact of Distributed Generation (DG) in Maine and recommend actions we consider appropriate.

The term "distributed generation" (DG) does not have a universal definition, but generally refers to smaller-scale generation located near the source of the load it serves. DG may include expanding Maine's pattern of small-scale generation at paper and forest product firms to smaller customers, expanding electric restructuring into a market-driven decentralized system, and continuing renewable development and demand side management. In this report, we focus on generation technologies with output below 5 MW that appear to have a reasonable chance of penetrating the market over the next five years.

This report should be read in concert with our two earlier reports, "Interim Report on Distributed Generation" developed by the Commission and "Assessment of Distributed Generation Technology Applications" developed by Resource Dynamics Corporation. Together, the reports provide a broad survey of the current status of DG technologies, set forth policy issues facing DG development in Maine and present conclusions and recommendations concerning the procedures that should govern the resolution of these issues.

B. Technical Potential of Distributed Generation

The Commission retained Resource Dynamics Corporation, a consulting firm that is closely involved in DG issues, to provide a survey of the current state of the art of DG technologies. Appendix A summarizes their major findings. Their report suggests that DG technologies can be roughly divided into three groups.

Current fossil-fueled technologies include reciprocating engines, typically fired by diesel oil or natural gas and industrial combustion turbine engines. Both are mature technologies that are currently used in Maine. Each may see incremental technological improvements over the next few years that reduce costs and emissions, but neither appears poised for further technological breakthroughs. Since many Maine customers who would benefit from these technologies have already done so, additional adoption is likely to be slow but steady.

New fossil-fueled technologies are primarily microturbines and fuel cells. Both technologies are still undergoing development and neither is mature enough to have a major impact in the marketplace over the next few years. In the longer term, each has the potential to make DG viable for all customers, including the smallest. We conclude that microturbines will be adopted at a slow but steady pace in the near term, particularly as replacement for costly line extensions and for peak shaving applications.

Renewable technologies are a broad class and not readily amenable to generalization. Wind power has made substantial strides in recent years and appears able to compete economically with on-grid power in some situations. However, the economic potential of wind is site specific. Photovoltaic (PV) solar technology will need additional development if it is to become widespread. Small hydro is well established in Maine, but new sites are unlikely to be available and existing facilities are finding it difficult to remain competitive.

A variety of industry groups have proven to be early adopters of diesel generation and would find emerging DG to be attractive for the same reasons. Large data centers and some industrial sites are potential adopters because of their need for quality assurance. Shopping centers and business parks might find DG an attractive alternative to line extensions, and industrial sites could consider DG as a lower-cost source of power.

As DG develops, utilities and their ratepayers will lose some contribution to utilities' fixed and stranded costs. We conclude that, in the near term (approximately five years), customers will adopt DG at a pace that will not put undue strain on utilities' revenues or other customers' rates. However, we intend to monitor the extent to which DG deployment or utility response hampers the elimination of existing stranded costs or creates new ones and to explore adaptive strategies if necessary.

C. Conclusions and Recommendations

Our basic premise in this report is that DG should compete on its intrinsic economic merits with other sources of electricity. This principle is relevant when considering operating procedures, when determining the payments and benefits associated with generation, and when providing access to the market. With this premise in mind, the study considers a variety of specific areas influencing DG.

Interconnection standards, the set of technical and commercial arrangements between the DG owner and the utility, appear to place financial burdens on smaller DG facilities and thus to play a significant role in the ability of DG to compete with on-grid electricity. Maine has made reasonable progress toward solving many interconnection issues. We have determined that the Commission will sponsor a stakeholder group to consider specific interconnection standards, to assure that all requirements are appropriate, reasonably uniform and do not place undue restriction on DG installations. This group will also consider methods for recognizing when DG deployment will result in the need to upgrade utility infrastructure.

Selling excess generation (i.e., generation beyond the needs of the associated consumer) requires procedures that are often difficult for a DG owner to accommodate. A DG owner has several options. First, it could sell directly to other retail customers, raising the possibility that it must comply with the requirements for a competitive electricity provider (CEP) or a transmission and distribution (T&D) utility under Maine law. We have reviewed such requests on a case by case basis and conclude that the law lacks clarity regarding the status of some DG applications. We recommend that the Legislature clarify the extent of regulation that should be exercised when a customer sells its DG output at retail.

Second, it could sell into the wholesale market, but because of costs and complex procedures, it is often difficult for DG facilities under 5 MW to access a market. A new competitive market for DG facilities' output currently exists and might expand over time. While this nascent market is developing, we intend to take steps to reduce or eliminate unnecessary costs of selling generation from small-scale facilities. Despite these activities, we are concerned that healthy market operations will develop with difficulty. Thus, as a precaution during the transition period, we recommend that the Legislature provide us with authority to order T&D utilities to buy the excess generation from distributed generators and resell it into the wholesale market if we determine that a sufficient number of buyers does not exist for small generation.

Third, it could take advantage of net billing. We intend to leave the current net billing rules unchanged at this time, thereby allowing net billing only for DG facilities that use renewable resources, produce below 100 kW, and are used for the facilities' and associated consumers' own needs**.** We conclude that expanding net billing to additional DG facilities would disrupt the existing balance between costs and benefits embodied in our current net billing rule, and does not appear necessary at this time to promote DG.

Rate design and rate structure issues are central to DG's ability to compete. A new investor in a DG facility will compare the cost of the DG investment to the revenue and/or cost savings that will result from the investment. In our view, the owner of a new DG facility should receive a savings equal to the true cost of generation and delivery that the DG facility avoids. This result will follow if all portions of on-grid utility service are priced in an economically efficient manner.

The ongoing costs that a T&D utility incurs to serve a customer are low in the short term because the utility already has its poles and wires in place and because the operating cost of the T&D system does not change significantly as usage changes. Because current core rates were designed for a vertically integrated utility, they do not always allow efficient price comparison of on-grid power and DG. However, because substantial amounts of T&D utility costs are currently recovered through usage sensitive charges, current rate structures do not uneconomically impede DG development and may, in fact, provide an uneconomic stimulus to DG. We have determined that the Commission will review core utility rates under the time frame already established for rate design proceedings. We also have determined that standby rates – the rates a DG customer would pay the T&D utility for backup service – will be reviewed after core rates have been re-established.

Current market generation costs vary significantly across the day. Market prices would likely reflect these variations if real-time meters were widespread. We conclude that the market for real-time meters will evolve and that current Maine rules will be appropriate as this occurs. We also conclude that evolving regional initiatives to develop mechanisms that allow customers to shave peak use without installing a real-time meter will further speed efficient on-grid pricing.

Utilities may currently offer reduced rates to customers who would otherwise leave the utility grid. This practice is likely to result in utility prices (when combined with generation prices) that remain lower than many DG applications in the near future. However, we conclude that this practice sends the appropriate economic price signal to customers and is in the best interest of the ratepayer base as a whole, and thus should continue.

DG sometimes provides benefits to the T&D utility's physical infrastructure. For this purpose, DG may be installed on the utility side of the meter or on the customer side of the meter. It may benefit the grid as a whole when a DG facility avoids the need for upgrading a constrained circuit, or it may benefit a single customer when on-site DG avoids the need to construct a line extension. Conversely, DG may impose additional costs associated with utility infrastructure upgrades. Currently, the price signals received by the market participants involved are often, but not always, appropriate. Therefore, making economically efficient comparisons is sometimes difficult.

Current law allows a T&D utility to own DG when necessary to perform its T&D obligations efficiently, and does not differentiate between the utility side of the meter and the customer side of the meter. We conclude that this law should remain unchanged and have determined that utilities should report to us regarding their efforts to consider DG alternatives to traditional infrastructure solutions. We further conclude that utilities should not be prohibited from owning DG on the customer side of the meter for T&D support, although there is likely to be minimal activity of this type because financial incentives are modest.

When investment in DG that serves only one customer is more efficient than investment in a line extension to that customer, price signals are appropriate when the customer must pay the full cost of the line extension. We have determined that utilities should examine their line extension policies for larger customers to determine if full customer payment is appropriate. We will re-examine line extension policies for smaller customers as DG technologies mature.

Whether utilities or their affiliates should be allowed to own or operate DG in the competitive generation market (as opposed to DG for T&D system support) is a significant policy decision. Allowing the utility or its affiliate to compete could result in more rapid DG development by allowing an effective participant into the market and by eliminating incentives for utilities to impede DG deployment. On the other hand, it may be inconsistent with the basic principles of electric restructuring in Maine and may inhibit development of a broader competitive market through the exercise of utility market power. We are concerned about potential market abuse resulting from the presence of utilities or affiliates in the competitive DG market, and we see no reason to deviate from current law that prohibits utilities from directly engaging in generation activities. Regarding affiliate involvement in DG deployment, we recognize that the Legislature has already made the policy decision to allow affiliates to enter the competitive generation marketing business subject to strict standards of conduct. However, we conclude that affiliates are no better positioned than other market participants to develop a healthy DG market, and we have concerns regarding market abuse when one player may potentially impede the activities of its affiliate's competitors. In addition, we are concerned about the incentive for a utility to cease offering discounts to retain customers that deploy DG through its affiliate, thereby increasing price pressure on other ratepayers. Thus, we recommend that the law remain unchanged, and that utilities and their affiliates continue to be prohibited from owning or having a financial interest in DG other than for T&D system support.

Finally, the report discusses a number of the broader issues upon which DG will have an effect, particularly environmental and overall energy policy.

II. INTRODUCTION

In its second session, the 119th Legislature passed a Resolve to Require an Examination of Distributed Generation (Resolve 1999, Ch. 107). The Resolve requires the Maine Public Utilities Commission (Commission) to submit a report on distributed generation by October 1, 2001. In February 2001, the Commission issued an "Interim Report on Distributed Generation" (the Interim Report) and a report by Resource Dynamics, Inc., a consultant engaged by the Commission, entitled "Assessment of Distributed Generation Technology Applications" (the Assessment Report). This final report is intended to be read together with the two earlier reports as the Commission's response to this legislative directive.[1]

The term "distributed generation" (DG) does not have a universally accepted definition, but generally refers to smaller-scale generation located near the source of the load it serves. DG is not a new concept, but dates back to the earliest days of the electric industry. For much of the twentieth century, however, small-scale customer-based generation could not compete economically with utility-owned centralized plants. These economics began to change in the 1970s, when centralized fossil fuel plant technology reached maturity and research and development brought forth new technologies such as combustion turbines and fuel cells.

In addition, customers' electricity and energy requirements are changing. Some industrial customers now meet combined electric and thermal energy needs through one process. Customers such as hospitals and computer-based firms consider power quality and reliability to be requirements, not preferences. Other customers desire renewable or environmentally benign power. In response to these factors and to changing federal and state laws, relatively small-scale generation became common among large industrial customers in Maine, particularly paper and wood product companies, and wind generation developed for customers who valued its benefits.

The convergence of three events suggests that smaller DG technologies – those below 5 MW - will soon be reasonable options for certain portions of the customer base in Maine. First, new technologies are approaching economic viability. Second, natural gas, the fuel of choice for many DG technologies, is becoming more widely available in Maine. Finally, electric restructuring has heightened customer awareness of electricity generation sources and the wisdom of examining options. A limited number of Maine customers are already installing DG of the type studied in this report, and cases testing requirements related to DG were brought before the Commission during 2000.

It is impossible to predict the long-run economic impact of DG. It could play a small role, serving a limited number of niche markets, or it could become a major part of the electrical supply system through energy campuses and sales into the wholesale market. In any event, the possibility that DG could soon become a mainstream tool

[1] All three of the Commission's distributed generation reports may be found at www.state.me.us/mpuc.

requires that regulatory policy take DG into account. The policy questions that Maine is likely to address in the near future include:

- Are there unnecessary or uneconomic barriers to the development of DG?
- Should standardized interconnection contracts be developed to simplify the process a DG facility must follow to connect to the electrical grid?
- Are policy changes needed to facilitate the sale of DG generation to the wholesale electric market? Who has jurisdiction over these changes?
- Is it desirable to make it less cumbersome for DG facilities to sell their output to other retail customers, either locally or regionally?
- Should Maine encourage DG as a means of providing customers with an alternative to buying electricity supply from the market and transmission and distribution services from the regulated utility?
- How should utilities' rates, including standby rates, be designed to allow DG to compete on its economic merits?
- How should the impact of DG on utility revenues – through increased stranded costs or increased costs of grid operation – be taken into account? In what circumstances should utility revenues lost to DG be shifted to remaining utility ratepayers?
- Do DG facilities have the potential to reduce electric transmission and distribution costs? If so, what is the best way to ensure that DG will be located and operated in a manner that ensures these benefits can be obtained?
- Should Maine allow or encourage utilities to own, operate, or finance DG facilities, either directly or through unregulated subsidiaries?
- To what extent should environmental ramifications be considered in setting DG policy?

These questions cover a broad range of economic, environmental, and energy policy issues. Generally speaking, the Commission's charge from the Legislature is economic regulation. Environmental policy and overall energy policy are developed and carried out in a variety of forums. Thus, this report focuses primarily on economic issues that affect ratepayers, DG owners, and utilities.

In our report, we follow one overarching principle: that all forms of generation should compete based on their inherent economic efficiencies.[2] One implication of this principle is that operational requirements should be similar under similar circumstances and should be commensurate with the benefits and risks associated with the generating technology. For example, interconnection and market settlement rules should be simpler for smaller generators when complexity is sensible only in the context of large generation units. Another implication of the principle is that all generation should pay for those costs it imposes on the electric transmission and distribution system and reap the benefits of any savings it produces. For example, if constructing a DG facility would be $100,000 more expensive than relying on conventional generation but would reduce distribution costs by $200,000, then the appropriate choice is to build the DG facility. On the other hand, if the DG facility creates no savings for the T&D system but a customer owning the DG lowers its electric bill by contributing less to stranded costs, the correct economic choice for the customer will not be the appropriate economic choice for Maine as a whole. A third implication of this principle is that all generation owners should have similar ability to reach the market. For example, a utility or its affiliate should not have access to information because of the utility's status as a monopoly.

While considering this principle, we acknowledge that it takes time to change policy and practices. In our report, we sometimes recommend waiting until a later date to make a change that would achieve the objective we have articulated. We do this when the disruption or risks created by the change outweigh the benefits in the near term, and when resources appear to be more effectively devoted to other activities.

In addition, we acknowledge that DG policy must be flexible. The penetration of DG in the Maine market will be influenced by technology costs and efficiency improvements, the price of fuels used by DG technologies, and the cost of purchasing on-grid electricity. Each of these is generally outside the control of the State, so developing flexible policies that are effective in a variety of situations is vital.

Section III of this report presents a broad analysis of likely DG use in Maine in the near term. The report then elaborates on the fundamental equity among generation forms. Section IV addresses the physical requirements DG must meet to interconnect with the utility. Section V discusses the sale of excess generation and Section VI discusses pricing policies. Section VII addresses the use of DG to support the delivery grid and Section VIII addresses ownership of DG by T&D utilities and/or utility affiliates. Finally, Section IX articulates some of the broader policy issues surrounding DG.

[2] The Legislature may, of course, for reasons other than economic efficiency, decide to promote or subsidize certain technologies or resources.

III. MARKET PENETRATION

In our investigation, we examined the viability of DG for Maine's customers in the relatively near term (approximately five years) and the impact that DG adoption might have on T&D utilities in Maine. Understanding viability and potential penetration can help guide policy for at least two reasons. First, if the technologies are economically and technically viable, but are artificially inhibited, Maine customers are being denied a low-price source of generation; policy makers should eliminate such situations if they exist. On the other hand, if DG is still immature, policy decisions can be made more slowly, allowing Maine to learn from other states' successes. Second, if DG penetrates the market quickly, the revenue loss to utilities and (perhaps) the resulting rate impact on utility customers will be onerous. On the other hand, if DG develops slowly, utility revenue losses may be offset by decreases in stranded cost obligations or by adjustments to rate design, and the impact on utilities and their ratepayers can be absorbed more easily.

In the following sections, we consider specific technologies, applications, and customers groups. Our conclusions are necessarily broad, as predictions are inherently speculative and uncertain.

A. Technology Viability

Predictions regarding the economic prospects of any technology are extremely uncertain. The relative economics among generation sources change as quickly as electric and gas market prices change. For example, recent capacity shortages in New York and California have significantly increased the viability of DG in those areas. On the other hand, marginally economic gas-fueled technologies become far less viable when gas commodity prices triple as they did briefly during the past year. The volatility of both markets is makes economic predictions difficult for us and for customers and firms making investment decisions.

In addition, emerging DG technologies often appear promising if efficiency improvements can be made to bring down prices. Predicting the speed of these improvements can be very difficult. Nonetheless, with these uncertainties in mind, we investigated the relative economics and advantages of each DG technology. We also considered specific customer groups that may be early adopters of emerging DG technologies.

Our Assessment Report summarizes the cost to install and operate various DG technologies (pages 3 and 25). These cost estimates may be compared with the average all-in cost of on-grid electricity[3] to make a rough estimate of the relative economics – from a potential customer's perspective – of DG and on-grid power.

Diesel generators, which are well established alternatives to on-grid electricity in all of Maine's utility territories, are shown to produce electricity at a cost between 7 and 14 cents/kWh. Average medium-sized customers pay an all-in price in excess of 12 cents/kWh for on-grid electricity in most portions of the State. Clearly, diesel generation is competitive with on-grid electricity in some instances. Customers with electricity use that "spikes" from time to time are likely to pay far more than average, and are thus more likely to find diesel generation attractive. However, if diesel fuel prices double, the all-in cost of diesel generation increases significantly. In addition, diesel creates noise and other environmental impacts. The relative advantages and disadvantages of diesel-fired DG have existed for many years. Utilities have responded to the threat of sales loss to diesel generation by offering discounted rates to retain customers (an issue discussed later in this report). In our view, a significant number of the customers who could switch to diesel have already done so, but it is reasonable to expect some continuing activity without sharp growth.

An analysis of industrial turbines yields similar conclusions. For some time, industrial turbines have been economically competitive for some large customers, particularly those that take advantage of combined heat and power. Many customers have installed the technology and some have received utility discounts to avoid installation. The situation is relatively stable, and we expect a steady level of continuing activity.

In the near term, microturbines appear to be the technology most likely to penetrate portions of the market that have been previously unaffected by DG. The least expensive of the microturbines, whose operating costs range from 12 to 22 cents/kWh, are competitive with on-grid electricity for average medium-sized customers. Customers with spiky usage have above-average on-grid electrical prices, making some microturbines a more economical generation source. Customers who could not accommodate the noise and environmental impacts of diesel generators might find the quieter and cleaner microturbines to be attractive. As stated in the Assessment Report, several units are available commercially, and others are expected to enter the market by 2002. Microturbines are versatile. They are designed to operate continuously,[4] so adopters could include customers willing to remove most of their usage from the grid

[3] The all-in rate is the total price a customer pays for electricity. It includes a T&D delivery charge and a generation charge. In our analysis, we used the current standard offer generation prices. However, approximately 40% of Maine's electric load is served by competitive electricity providers, who are likely charging prices below the standard offer price.

[4] Installation costs are high, but running costs are relatively low and the equipment requires minimal downtime for repairs or maintenance.

rather than respond in real-time to on-grid electricity price signals. This makes microturbines potentially suitable for medium sized customers whose load could be served by the technology, because these customers generally do not have time-of-day generation or utility rates but do pay a demand charge. It also makes microturbines attractive to customers in remote locations, who might be required to pay for costly three-phase line extensions. Microturbines can also be used for peak shaving, so customers seeking to hedge against volatile electric prices will find them attractive as well.

These factors make microturbines appear to be viable and adoptable almost immediately. However, in our view, three considerations will limit the speed of adoption. First, as with all DG, many customers are not prepared to make the effort required to search out new technologies, learn new skills, or manage new risks perceived as necessary to manage on-site generation.[5] Second, natural gas is not yet available in most of Maine, limiting the market primarily to propane-fueled microturbines.[6] Finally, utilities can usually offer price discounts that will lower the all-in price of on-grid electricity far below the cost of microturbines. Because of these factors, we conclude that microturbines will not make significant inroads into the market within the next five years. However, slow, steady adoption is likely to occur, particularly when three-phase power is not currently available, setting the stage for wider scale adoption when the technology matures.

Fuel cells and photovoltaics are currently uneconomic for most customers. Some customers will adopt these technologies for their environmental benefits. However, we conclude that widespread adoption will depend on future technological and production advances that do not appear likely in the near term. Small-scale wind generation has been successful in Maine for some time, and has benefited from Maine's net billing rule. Wind generators that serve on-site needs will continue to be adopted by environmentally conscious consumers with appropriate sites.

Finally, small-scale hydro generation, a form of DG that is well established in Maine, will experience no significant increase in availability. However, it is possible that some hydro facilities will become economically uncompetitive after existing contracts with utilities expire. To avoid this, the Legislature, the Commission and stakeholders are considering actions that will lower costs and improve the ability of these facilities to sell their generation. Because small-scale hydro is stand-alone generation that generally is not designed to serve the needs of a single or a few customers, it does not fall within the strict range of technologies that are addressed by this report. However, some problems encountered by this industry are shared by all DG technologies. These shared issues are included in this report, and problems unique to hydro generation are further addressed in other forums.

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[5] Microturbines require less skill and attention to operate than diesels, so this barrier is likely to diminish as the technology becomes better known.

[6] Microturbines may also be fueled by landfill gas.

We further conclude that, in the near term, fossil-fueled DG is likely to involve hedging applications such as peak shaving.[7] The unpredictability of both electric and gas prices will cause some customers to hedge their energy costs by relying on dual generation sources, switching between on-grid electricity and gas- or diesel-fueled DG as economics dictate. Such switching is most effective when a customer is receiving the market's price signal, either through real-time electric prices or time-of-use rates. We see no evidence that retail generation suppliers are offering customers real-time prices, and therefore we conclude that fully effective peak shaving applications are some years away. However, utilities' time-of-use rates and demand charges can be strong inducements to use DG to minimize prices when the customer's load is highest. This approach favors microturbines or diesel generators, which are easily used for planned peak shaving.[8]

B. Impact on Utilities

We also investigated the impact on utility revenues if DG is adopted by significant numbers of customers. We considered the loss in revenue that would result if specific customer groups replaced on-grid delivery with DG. Our analysis is broad and should be viewed as an upper bound to revenue impacts. The impact of installing a DG technology is site-specific. A DG installation might cause the utility to lose a customer's revenue stream, it might avoid the costs of a system upgrade, or it might create the need for investment in system changes. Also, DG might be used for peak shaving only, or the customer might continue to pay standby rates to the utility. However, to develop some insight into potential impact, we present here the gross revenue that could be lost from certain customer groups if they left the electric grid altogether and their exit produced no offsetting savings.

Supermarket chains are typical of likely early adopters. They have converted to diesel generators elsewhere and have shown the ability and willingness to do so in Maine. They often possess sophisticated, nationwide energy management systems to manage their significant cooling and lighting loads; these systems are well suited to integration with a DG technology. As a rough estimate, if most of Maine's chain supermarkets converted to microturbines or diesels, CMP would lose about 140M kWh of sales per year, accounting for more than $4M annually, or 1% of CMP's

[7] A procedure that is being offered by energy service companies in other states is peak sharing. An energy service company manages a customer's load, on-grid power, and DG generation to minimize the customer's energy bill. Savings are shared between the energy service company and the customer.

[8] Microturbines take a few minutes to cycle on, so they can be used to respond to changes in prices but are less useful for emergency backup. Diesel engines can also be cycled on quickly. Peak shaving is generally a better use for diesels than base load generation, because environmental requirements limit the number of hours that diesel generation can operate.

revenues.[9] If all medium-sized general food stores converted to DG (an unrealistic scenario, but included here to provide a general magnitude), CMP would lose over 200M kWhs, or almost $9M, annually. We also considered other large national chains. If three or four of the largest national retail chains converted to DG, CMP would lose about $3M, and if three or four national hotel chains converted, CMP would lose approximately $1M in annual gross revenues.

In other states, some fast food restaurants and convenience stores have received considerable press coverage as pilot DG projects. We do not believe that these projects represent the fast food or convenience store markets as a whole, and we see no evidence that these companies will be early adopters in Maine.

Large data centers are cited as candidates for DG because they require exceptional power quality. For these customers, the cost of an outage (rather than the overall cost of electricity) is significant and surges or dips in voltage are not acceptable. While DG literature suggests that these customers will adopt emerging DG such as microturbines for power quality, we have found that they currently operate successfully with existing on-grid and back-up arrangements. For example, data centers may use a combination of redundant feeds, grid-charged batteries, and uninterrupted power supply (UPS) systems as a primary power source that guarantees steady voltage and no outages. Diesel generators are successful as back up because they run for very few hours and can therefore meet emissions requirements. Thus, we conclude that these customers will use small amounts of DG as backup power, but they will cause minimal growth in the emerging DG technologies in the near term.

Hospitals, large colleges, and ski slopes have shown the technical ability and willingness to convert to diesel or cogenerated power sources. In general, these customers have already pursued options and either adopted generation alternatives or received utility discounts to avoid leaving the grid. It is unlikely that new technologies will be adopted on a large scale by these customers in the near term, until those options drop significantly in price. However, as a reference point, if all hospitals left the grid, CMP would lose more than $5M, or more than 1% of its annual revenues.

Finally, shopping centers and business parks are potential adopters of DG as replacements for costly line extensions or as grid backup to ensure unusually reliable power. Similarly, single customers whose business growth requires customer-financed extension of 3-phase power to the site are likely adopters. In these situations, DG would replace new revenue, so its effect on utilities and their ratepayers is muted.

Virtually any industrial site could consider microturbines for peak shaving. Many industrial sites have spiked loads and therefore can reduce costs by lowering their peak demand. It is difficult to analyze the potential impact because industrial customers do not fall neatly into industry groups. However, as a reference point, if one medium

[9] We use CMP as an example because its service territory encompasses the majority of Maine's population.

sized industrial plant left the utility grid, CMP would lose between $10,000 and $70,000 annually.

From this analysis, we conclude that, in the near term (approximately the next five years), the customer groups that are likely to adopt DG will do so at a pace that will not put undue strain on utilities' revenues or result in substantial price increases to the general body of ratepayers that continue to obtain all their needs from the grid. However, we recognize that predictions are inherently uncertain. Thus, we intend to monitor the extent to which DG deployment or utility response slows the elimination of existing stranded costs or creates new ones and to explore adaptive strategies if necessary.

IV. INTERCONNECTION

Our Interim Report (pages 7 through 10) addressed interconnection agreements, procedures, and costs. These issues are important because interconnection procedures are cost-prohibitive for some DG technologies. Stakeholders disagree on the appropriate technical and safety procedures that should be required and on the appropriate allocation of costs between generator and utility. Affected entities are just beginning to focus on appropriate interconnection procedures, and it appears that progress can be made in resolving disputes. In our view, Maine has made reasonable progress toward solving some interconnection issues, but many remaining issues must be addressed.

In Maine, affected parties have voluntarily solved some of the interconnection disagreements. For example, stakeholders in CMP's territory have developed an Interconnection Agreement appropriate for smaller generators (less than 5 MW). Texas, New York, and California have used a collaborative process to address competing stakeholder interests and develop interconnection procedures. Finally, the Institute of Electrical and Electronics Engineers (IEEE) will soon approve standards that were developed through stakeholder collaboration. The success of these activities convinces us that disagreements on interconnection issues in Maine may be solved through stakeholder collaboration.

We have determined that the Commission should sponsor a stakeholder group to develop recommendations on the following technical interconnection issues, to be applicable for DG of 5 MW and below:[10]

- safety standards;
- design requirements (e.g., interruption devices, synchronizing equipment);
- operating requirements (e.g., power factor, disconnection, islanding);
- metering requirements;

[10] This group should consider recommendations for very small scale DG (less than 100 kW) that are less stringent than requirements for larger DG (up to 5 MW).

- verification testing;
- type testing;
- insurance requirements;
- standardized Interconnection Agreement;
- procedures and time frames for interconnecting;
- fees; and
- dispute resolution.

The Commission would consider the group's recommendations, approve or revise the recommendations, and decide matters on which the group could not reach consensus. The group's operating principle should be that unnecessary barriers will be removed, but actions necessary for reliability, safety, and appropriate cost responsibility will be maintained. The group should also consider guidelines for identifying when DG deployment will create the need for upgrades to the electric grid or will jeopardize the safety of the grid. The group should use existing interconnection procedures as starting points.

State jurisdiction to adopt uniform interconnection standards may need to be clarified. DG of the size addressed in this report is generally interconnected at the utilities' distribution facilities. Distribution facilities are considered state jurisdictional. However, the Federal Energy Regulatory Commission (FERC) has jurisdiction over costs and practices related to the transmission of electricity. Thus, it is not clear where jurisdiction lies when a DG facility is connected at the distribution level, but electricity from the project is sold into the regional grid.

Despite this jurisdictional uncertainty, the New York Public Service Commission has adopted uniform interconnection standards for DG.[11] However, the FERC has recently issued a decision in which it accepts jurisdiction over a disputed interconnection agreement for a facility interconnected at what had been considered distribution facilities.[12] Additionally, CMP files with the FERC interconnection agreements regarding generation interconnected at the distribution level.

We recommend developing solutions at the state level. Should the FERC rule that it has jurisdiction over any of the decisions developed in Maine, our solutions will inform federal efforts to address the same issues.

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[11] *Opinion and Order Adopting Standard Interconnection Requirements for Distributed Generation Units,* Case 94-E-0952, Opinion No. 99-13 (NY PSC, December 31, 1999)

[12] *Detroit Edison Company,* 95 FERC ¶ 61,415 (June 15, 2001). This proceeding involved a 780 MW facility.

V. EXCESS GENERATION

As discussed in the Interim Report (pages 17 through 21), the economic viability of a DG project can sometimes be enhanced if generation in excess of the customer's needs can be sold or used at other locations. The options that exist for excess generation are: sale to other end users (either as a competitive electricity provider as defined by Maine law or directly to a neighbor or tenant); sale into the wholesale market; and net billing. The sale of excess generation by owners or sponsors of DG projects who are not otherwise in the business of selling electricity involves a certain level of sophistication whether the sale is at retail or into the wholesale market.

In our view, DG projects will generally find it possible to sell the excess generation created as a byproduct of their on-site generation. Because of their small size, these generators are unlikely to sell their output directly into the NEPOOL wholesale market. Rather, a secondary market is likely to continue to develop consisting of larger-scale generators that wish to purchase additional generation to fulfill environmental or supply requirements. We discuss issues associated with sales options in the following sections.

A. Sale Directly to End Users

Offering electricity to the "public" at retail requires the seller to obtain a competitive electricity provider (CEP) license and to comply with various rules, including sophisticated electronic business transactions and settlement procedures. In addition, if the seller owns or operates facilities to deliver power to third parties, the seller could become a T&D utility requiring Commission authorization before any transactions occur.[13] The seller is not a CEP or a T&D utility if the provided service is not to the "public." Generally, a transaction would not be considered public if the power is provided to the selling entity itself, to an affiliate, a tenant, or a third party with a nexus or relationship to the seller that goes beyond the electricity transaction. However, the law does not clearly address all situations that occur when DG is installed, and the Commission determines whether a transaction is public in nature on a case-by-case basis depending on the specific facts presented.[14] Recent Commission rulings have concluded that the provision of service to even a single (or relatively few) nearby neighbor would generally be considered CEP service as well as T&D service if the

[13] See 35-A M.R.S.A. § 2102.

[14] In a recent decision, the Commission cited the following considerations in making its determination: the proximity of the generator to the customer; a commercial or corporate relationship that goes beyond the sale of electricity; limitation on the numbers of customers that could be served; the provision of power solely from the seller's generator as opposed to the utility grid; and the absence of evidence that the dealings between the parties involved sham transactions. See *Request for Investigation of Plans of Boralex Stratton Energy to Provide Electric Service to Stratton Lumber*, Docket No. 2000-653 (April 6, 2001).

service provider owns or operates delivery facilities, unless the end user is affiliated with or has some other relationship to the service provider unrelated to electricity sales.

For the larger, more sophisticated DG owners, the CEP requirements generally do not provide significant barriers.[15] It is likely, however, that DG owners will continue to explore the extent to which the Commission will allow sales to neighbors without deeming the DG owner to be a CEP.

If the seller becomes a T&D utility by virtue of its provision of electricity, more serious issues arise regarding the impact of stranded costs on existing utility customers and the implications of multiple utilities in an existing service territory. The Commission would carefully consider the impact on the existing T&D utility and its ratepayers before authorizing transactions that constitute T&D utility service. For its part, the generator is likely to find the legal requirements of a T&D utility to be burdensome even if the Commission allowed the transaction to occur. Thus, in our view, there will be little or no development of DG that includes ownership of delivery facilities to the public. However, as with the CEP requirements, it is likely that DG owners will continue to explore the extent to which the Commission will allow sales to neighbors without deeming the DG owner to be a T&D utility[16].

We conclude that the lack of clarity in the current laws as to when a generator is required to be licensed as a CEP if it is selling to the public, or to be deemed a T&D utility if it owns delivery facilities, creates unnecessary uncertainties for customers considering DG installation. We recommend that the Legislature clarify the extent to which distributed generators may sell or deliver generation without complying with the requirements imposed on CEPs or T&D utilities. We offer two suggestions for consideration. First, legislation could authorize the Commission to waive the requirement that a small-scale generator be treated as a CEP or a T&D utility if the Commission determines that stranded cost issues are resolved in an equitable manner. Second, the law could designate a category of small-scale generators that are not T&D utilities or CEPs, but are subject to a minimal level of regulatory oversight.

B. Sale to the Wholesale Market

The Interim Report discusses wholesale market operations (pages 18 and 19). A DG project has two basic options regarding the sale of excess electricity at wholesale: direct sales to a third party supplier or sales into the regional spot market. In either case, the transaction must conform to the rules and requirements of a regional

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[15] The only exception could be the resource portfolio requirement, which would prevent the sale of the retail sale of energy from a project that is not “eligible” under Maine law. However, many DG projects are likely to be fueled by eligible resources.

[16] The Commission has not been asked to consider the status of an “energy park,” where a group of customers share one or more DG facility for electricity, process heat, and/or higher power quality.

system administrator -- ISO-NE or NMISA.[17] Thus, the seller of excess electricity from a DG project must either be a participant in the New England Power Pool (NEPOOL) or the NMISA, or have a commercial relationship with such a participant. For larger DG projects (e.g., above 5 MW), this requirement does not create unreasonable barriers. However, for smaller projects, the costs and procedures associated with regional requirements could be prohibitively complex and expensive. NEPOOL has sought to address this problem by allowing for less complex procedures for facilities of less than 5 MW. However, even the costs of these less complex procedures may be prohibitive for the smallest facilities.[18]

The Commission is currently engaged in discussions with interested persons regarding market barriers for small hydro facilities (generally 1 MW or less), and these discussions will likely be relevant for other small generators.[19] From these discussions, we conclude that the primary costs that currently present substantial barriers for small hydro facilities are insurance requirements and metering expenses. We are exploring with utilities the elimination of specific insurance requirements, an approach that is consistent with the current policy that eliminates insurance requirements of renewable generators that participate in the net billing program.[20] Utilities have insurance policies that cover damage expenses, and the financial risk would be transferred to the utility and its ratepayers. However, based on their past performance, small hydro facilities are unlikely to cause significant damage to the utility grid or resources. Other states, notably New York and Texas, have reduced or eliminated insurance requirements to remove DG barriers.

In addition, we are working with utilities to determine whether requirements for small hydro facilities to install hourly meters can be removed consistent with regional and state settlement processes. More generally, we will continue to work on the state, regional and federal levels to ensure that the smallest generators are not faced with unreasonable barriers or costs and have reasonable access to the market for their generation.

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[17] NMISA, the system administrator in northern Maine, does not operate a spot market; wholesale sales in the region occur directly through contracts among participants.

[18] In addition, because of their location, some small-scale generators that sell into the wholesale market must pay non-PTF charges. These charges create an additional competitive disadvantage that is avoided if the generator sells to a NEPOOL participant that serves local load. Non-PTF charges are within FERC jurisdiction.

[19] These discussions are occurring in the context of a request by the Utilities and Energy Committee in a letter dated May 3, 2001, that the Commission explore potential market barriers for small hydro facilities. In response to this letter, we will provide a report on the viability of small hydro facilities and our activities regarding market barriers before the next legislative session.

[20] A facility's owner may obtain whatever insurance it considers adequate for its own business protection.

We do not know whether NEPOOL or FERC will, in the near future, change the procedures by which the smallest generators sell into the wholesale market. Thus, the smallest generators will continue to find the process expensive and onerous. We will support and participate in the development of such rules when they are addressed.

At this time, there appear to be wholesale buyers that are willing to buy excess electricity from even the smallest generators, enabling the latter to avoid the expense of joining NEPOOL. We do not know whether this market will persist or whether current buyers would be interested in electricity from a small generator that does not qualify as an "eligible resource." However, it is our view that the market is likely to grow as the region's Generation Information System is developed and the market matures.

Although we are taking steps to eliminate unnecessary barriers and we have observed a nascent market for DG output, we are concerned that a healthy market will be slow to develop. Thus, as a precaution during a transition period, we recommend that the Legislature authorize the Commission to adopt rules that would require T&D utilities to sell the output of generators of 5 MW or less into the spot market and to compensate generators based on the clearing prices. However, the Commission should be authorized to adopt such rules only upon a finding that a reasonable market does not exist for small generators, and should be required to consider whether the capacity limit should be lower than 5 MW and whether the generator should compensate the utility directly for any incremental administrative costs.

C. Net Billing

As discussed in the Interim Report (page 18), generators that produce 100 kW or less and are fueled by a renewable resource may take advantage of excess production through net billing.[21] Under net billing, which is intended to facilitate the viability of small renewable generators, generators may offset their electricity usage with their own generation. Chapter 313 allows generators to roll over excess generation for a 12-month period, but does not allow generators to sell excess generation. By not allowing the sale of excess generation, the Commission intended to limit net billing to a generator's own electricity needs. This approach recognizes both the benefits of net billing and its costs in terms of utility administrative expense and lost revenue.

Net billing, as currently implemented under Commission rules, does not include the insurance and metering requirements that often appear to be a serious impediment to smaller generators selling directly into the wholesale market. For this

[21] The Commission adapted existing net billing rules to the restructured electric industry through the adoption of Chapter 313 of its rules. *See Order Adopting Rules and Statement of Factual and Policy Analysis*, Docket No. 98-621 (Dec. 10, 1998) (Chapter 313 Order).

reason as well, net billing is a beneficial option for those small generators that are eligible.

The Commission has recently interpreted the net billing rule to clarify its applicability. For example, although we concluded that the rule does not permit the net billing of accounts of individual members of an association against the output of a hydro facility, we held that a generator may net bill against its usage in several premises as long as they can be considered proximate to the generating facility.[22] In another ruling, the Commission found that a net billing customer is not required to own the generating facility as long as the facility is dedicated to the customer's use.[23]

It has been proposed that we expand net billing eligibility to generators of all fuel types, while retaining a size limitation and the requirement that the generation be used primarily to furnish the customer's electricity needs. Net billing could also be expanded to allow excess generation to be sold into the market rather than used to offset the generator's future usage.[24] However, such actions would upset the current rule's balance of costs and benefits, and we have thus far declined to expand eligibility.

Net billing enables small generators to avoid onerous regional wholesale market procedures and costs without imposing significant technical or financial risks on the utility grid or on utility ratepayers as a whole. To ensure that these benefits are retained by the net billing program, we conclude that at this time, net billing rules should not change. Because of the costs and lost revenues born by utilities and other ratepayers, net billing is not the most efficient way for entities that generate excess electricity for profit to sell into the regional market.

Net billing is essentially a subsidy in that it allows net billing customers to avoid paying some of the costs of the T&D system that similarly situated customers who do not net bill must pay. For this reason as well, we conclude that, at this time, net billing should not be expanded to encompass other forms of DG. Rather, we have determined that all attempts to remove unwarranted barriers for direct sales into the wholesale market be exhausted. The Commission will re-examine expanding the scope of net billing if, within the next few years, economic access does not develop for generators of 100 kW or less.

[22] Hydrotricity, Request for Waiver of Chapter 313, Docket No. 2001-27 (April 3, 2001).

[23] G. M. Allen and Sons and Endless Energy, Request for Advisory Ruling, Docket No. 2001-259 (June 12, 2001).

[24] A recent FERC ruling supports State authority over net billing issues, so the Commission appears to have the authority to expand the scope of its net billing rule. MidAmerican Energy Company, 94 FERC § 61,340 (March 28, 2001)

VI. ELECTRICITY PRICING

The Interim Report discusses the role that on-grid prices play in influencing the viability of DG (pages 13 through 16). On-grid pricing structures and practices are important because different structures can make DG relatively more or less economical. A customer considering installing DG must weight the savings from reduced purchases of generation from a competitive supplier (or the standard offer) and of delivery services from their local T&D utility. This means that a key element in DG policy is the design and structure of utility T&D rates.

Most of Maine's non-residential customers pay for T&D service using their utility's core rates,[25] which contain a relatively modest fixed customer charge, a significant per-kW demand charge, and a per-kWh energy charge. Residential and small businesses pay for T&D service with per-kWh rates. If a customer produces its own generation but receives backup power from the grid, the customer pays the T&D utility using a standby rate, which is approximately equal to the utility's core rate. Finally, some customers pay for their T&D service using a reduced rate that is made possible by flexible rate plans that are approved by the Commission and used to retain customers who would otherwise leave the utility grid.

Maine's customers purchase generation in the open market or through standard offer service. Currently, it appears that open market prices primarily take the form of per-kWh charges that sometimes vary by season or time of day. Customers who take standard offer generation service also pay per-kWh charges that vary by season and time of day for the largest customers.

In the following sections, we consider whether price structures in place today constitute an unwarranted barrier as they relate to DG viability.

A. Core T&D Rate Structure

Our Interim Report discusses the fact that a utility's *rate structure* (as distinct from the rate level) influences the economics of DG in instances when a customer with DG remains on the grid (pages 13-14). If the utility's rate contains a high fixed charge component, with a correspondingly low variable per-kWh charge, a customer's savings will be relatively small when serving a portion of its needs through DG. If the utility's rate contains a high per-kW demand charge, savings depend upon the timing of DG use. Finally, if the utility's rate is solely per-kWh, savings from DG will be significantly higher. In our view, current utility rates probably offer an artificial incentive to install DG, because the per-kWh charge is likely to be higher than is optimally efficient given the utility's underlying cost structure.

[25] Core rates are those charged to all customers who do not receive a discounted rate as allowed by a utility's Alternative Rate Plan.

Economic theory suggests that efficient utility rates should reflect the marginal cost of delivery. Current utility core rate structures were established when utilities' costs included generation. When compared with a fully integrated utility, a distribution utility has far fewer variable costs because most costs result from capital investment and fixed business costs that do not vary with usage. Thus, economically efficient distribution utility rates should probably have a *higher* fixed charge component to allow recovery of fixed capital costs, and a *lower* per-kWh component to recover ongoing variable costs, than currently exist. Such rates would be less advantageous to DG than currently existing rates. During 2001 and 2002, we will conduct formal proceedings to redesign the rates of Maine's three investor-owned utilities to bring the rates closer to a design that reflects the utilities' underlying cost structures.

We have determined that the Commission will continue to periodically review each utility's rate structure, as it will do in the upcoming rate design proceedings, and direct modifications consistent with sound economic principles. This will lead to appropriate price signal to customers comparing on-grid and distributed sources of generation.

B. Generation Market Costs

A customer's on-grid electricity price includes both T&D and generation costs. The same price structure principles refer to both components. In our view, the market will eventually charge economically efficient generation prices, thereby contributing to a level economic playing field for DG. However, there are two features of generation pricing that policy makers can influence in the near term.

First, generation costs show significant time-of-day variation. Some forms of DG, particularly peaking DG, should be able to benefit from these variable prices by running only during those hours when the generation prices are relatively high. Currently, a DG facility could only use this strategy if it had installed a real-time meter (i.e., a meter that records electrical use by hour) and was being billed for power delivered through the grid on a read-time basis. Currently, the expense of hourly metering and billing is cost-prohibitive for smaller customers, so DG used for peak shaving is inhibited.

This barrier to efficient DG use will diminish over time, as meter costs drop. Current state rules are appropriate for the equitable treatment of real time meters, so no unreasonable uneconomic barriers inhibit their adoption.

In addition, because of the widely cited problem that the current generation market lacks demand response during short periods of unusually high prices, regional administrators are developing mechanisms that allow customers to shave peaks without installing a real-time meter. This will mitigate the barrier that meter costs present to the DG market to the extent that reductions in network load can be reliably determined.

Second, we will likely continue to determine the structure of standard offer generation rates for some customers in the immediate future. We have determined that we will continue to consider the structure of the standard offer bid in the price charged to retail customers, as we have done in the past. However, factors that we must consider when setting standard offer rates are complex and far-reaching, and we should consider price structure as only one of these many factors.

C. Standby T&D Rates

Our Interim Report discusses standby rates (pages 14 and 15). As with utility rates in general, standby rates with a high fixed component are disadvantageous to DG economics when a customer remains connected to the grid because the customer will continue to pay that fixed component after installing DG. The Commission has not issued any decisions as to the proper standby rate structure for T&D utilities.

Standby rates, like core rates, should reflect the marginal cost of providing standby service. Current utility standby rates are essentially equal to current utility core rates, and are unlikely to be optimally designed. They contain advantages and disadvantages to DG customers – the customer pays a potentially costly demand charge for the load obtained on standby but pays a relatively low fixed charge in each month that standby is not used. Because current standby rates appear to be acceptable to most customers and because their re-examination will take significant amounts of time and resources, we intend to defer redesigning standby rates until after utilities' core rates are redesigned in the currently pending proceedings.

Thus, we conclude that current standby rates are not an unreasonable barrier – rather they have offsetting features. We therefore conclude that there is no immediate need to revise standby rates to promote DG but that they should be examined in a future proceeding.

D. Flexible Pricing

Our Interim Report discusses the ability of utilities to offer reduced prices to customers who would otherwise leave the utility grid (pages 15 and 16). Under its Alternative Rate Plan (ARP), Central Maine Power Company may reduce its rate to a customer as long as the reduced rate exceeds CMP's marginal costs (plus a pre-set adder). Bangor Hydro-Electric Company and Maine Public Service Company currently may offer similar discounts subject to Commission approval.

The discounted utility price, added to the customer's cost of generation, is less costly than the DG alternative in many instances. Utility discount pricing is likely to limit the penetration of DG primarily to cases where power quality or environmental concerns are the customer's goal, where combined heat and power capability lowers the relative price of DG, or where a costly line extension is required. However, as long as utilities do not price below their marginal cost, this result is not uneconomic or otherwise inappropriate.

The utilities' short run marginal distribution costs are close to zero when the distribution line is in place and is not operating at full capacity. Transmission marginal costs are also low – less than 1 cent/kWh. A significant difference between utility and DG costs is the maturity of the capital investment. The utility has already committed the capital investment to serve existing customers; the distributed generator has not. Thus, the utility's marginal cost to serve the customer in the short term includes only its relatively low variable costs, whereas the distributed generator's cost to serve includes capital investment as well as variable costs.

However, in actual practice, the utilities' marginal cost floor (i.e., the price that DG must "beat") is set at a value that includes longer-term costs to maintain and upgrade the line.[26] Thus, the floor prices reflect a reasonable compromise between near-zero short-term variable costs and the full cost of doing business. Nonetheless, they are considerably lower than the utilities' core rates.

It should be noted that, when considering utility price discounts, policy makers must look beyond the single customer who is comparing generation sources. As discussed in the Interim Report, flexible pricing provides an advantage to all utility ratepayers because the discounted rate preserves a portion of the contribution made by the customer to the utility's fixed costs. If the customer left the utility grid, eventually the remaining ratepayers would be required to pay for those fixed costs.[27]

In our view, the current flexible pricing policy sends the appropriate economic price signals and is in the best interest of individual customers and the ratepayer base as a whole. We conclude that it would be inappropriate to restrict the current flexible pricing ability exercised by Maine's utilities, even though restricting that ability might stimulate DG development. The current policy creates the correct economic price signal to a customer who is comparing two sources of generation and provides benefits to all remaining customers.

E. Stranded Cost Bypass as a Pricing Issue

In our view, DG should not be considered economic simply because it allows a customer to avoid stranded costs. Stranded costs were created by public policy, and should be apportioned to all ratepayers. The most efficient economic comparison is between the true cost of running both businesses – on-grid generation plus T&D marginal costs as compared with DG. Including stranded costs in one price and not the other would result in DG becoming simply a stranded cost bypass

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[26] The average long-term marginal costs are based on historic capital investment levels.

[27] During the duration of a flexible pricing plan, the utility generally may not raise its rates to recover these lost contributions to fixed costs; rather, shareholders absorb the loss or the utility must offset the loss through cost-cutting (except for portions that may be recovered through earning sharing mechanisms).

mechanism. We re-iterate the conclusion made in the previous section that no change should be made to Maine's current flexible utility pricing policy to artificially promote DG.

VII. DG AS A UTILITY RESOURCE

The Interim Report discusses the benefits of DG as a means to improve the physical infrastructure that delivers power to customers (pages 21 through 23). DG as a T&D resource is relatively new, but is under serious consideration at utilities and in the DG literature. The topic is important because this application may be a significant market for DG technology and may have the potential to benefit all utility ratepayers.

DG can be installed on the utility side of the meter or on the customer side of the meter. For example, DG can be installed at the substation or placed at the end of a long circuit to increase voltage to a constrained area of the grid. It can also be installed on an individual customer's site as an alternative to constructing a line extension or to avoid upgrading the local distribution grid to accommodate load in that area.

In the following sections, we consider whether existing regulatory and legal provisions and utility practices appropriately accommodate DG used to support the T&D utility grid.

A. Capital Investment Required to Support the Grid as a Whole

Traditionally, utilities have upgraded portions of the distribution system as they became constrained or could no longer provide adequate quality because of overall load growth or aging equipment. DG may sometimes be an alternative to these upgrades. In this instance, DG may be implemented in either of two ways – on the utility side of the meter (in the form of voltage or balancing support) or on the customer side of the meter (in the form of load reduction on the utility grid).

In enacting Maine's restructuring law, the Legislature recognized this potential benefit by allowing an exception to the prohibition on utility ownership or control of generation assets when necessary for utilities to perform their T&D obligations in an efficient manner.[28] This is an appropriate deviation from the general restructuring goal of separating the generation function from T&D services, because utilities are uniquely positioned to determine when the installation of DG is more economic than T&D system construction or upgrades. Utilities are under a general obligation to operate their systems in a least cost manner consistent with industry standards and practices. Thus, we expect utilities to continually evaluate whether the installation of

[28] 35-A M.R.S.A. § 3204(6). Pursuant to this authority, the Commission permitted BHE not to divest diesel generators so they can be used for voltage support in the Eastport area.

DG represents a more economic means to meet their obligations relative to traditional T&D system construction.[29]

Current ratemaking practices give utilities the correct financial incentives to install DG on the utility side of the meter. As with all T&D system construction, the capital cost of DG would be included in the utility's rate base and, as long as the generation is delivered through the utility's system, there would be no loss of revenues.[30] These proper incentives are enhanced by Maine's alternative rate plans, under which a utility may retain profit that is realized by reducing costs.

Financial incentives may not, however, appropriately facilitate the installation of DG on the customer side of the meter for this purpose. Although the law does not prohibit utilities from owning DG on the customer side of the meter (when used as an alternative to system upgrade), utilities will not have the financial incentive to do so unless the price the customer pays to the utility for the DG generated on its side of the meter includes stranded costs and any other non-marginal costs which are included in the T&D rate. Customers also would not have the financial incentive to install DG for this purpose unless the utility agreed to share at least a portion of the distribution savings with the customer.

We conclude that no legislative changes are necessary. First, current law authorizes utilities to own or control DG when it is the most efficient means of maintaining T&D system reliability. Although we will monitor utilities pursuant to our general ratemaking authority to assure that utilities are considering the installation of DG when it is the least cost alternative, monitoring opportunities will be limited in the near term future. Therefore, we have determined that we will require utilities to report to the Commission annually on their efforts to consider DG alternatives to distribution system upgrades, and report the reasons for the selected alternative. The reporting should include at least the three categories discussed in these sections (portions of the grid that are constrained because of general load growth, portions that require upgrade because of a single customer's growth, and line extensions) and should include consideration of DG on the utility and on the customer side of the meter. This reporting should ensure that Maine's utilities reasonably consider DG and will be a learning tool during the first few years. Based on the reporting results and the evolution of DG, we will consider opening an investigation to determine whether the utilities have used DG efficiently and what forms of DG are most efficient to support the T&D grid.

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[29] Utilities have generally not considered DG as an alternative to T&D construction until recently. However, it appears that some utilities now seriously consider DG for this purpose.

[30] The utility must sell or otherwise dispose of the generated power through a means compatible with regional procedures. While disposing of small amounts of generation can be problematic for smaller entities, a utility is likely to be able to accomplish it more easily.

In addition, we do not recommend that legislation prohibit utilities from involvement with DG on the customer side of the meter for T&D system efficiency, although we do not expect significant activity of this type. Finally, we do not recommend changes that would try to better match implementation costs and the revenue impacts that are experienced by a utility when DG is installed on the customer side of the meter. We believe that there is ample opportunity for other effective uses of DG; implementing more appropriate incentives in this area is simply not needed at this time. As the DG market matures, we will reconsider whether policy changes should be made to eliminate this barrier to some DG applications.

B. Capital Investment Required to Serve a Single Customer

In the previous section, we discussed DG when a portion of the distribution system is constrained or cannot provide adequate quality because of overall load growth or aging equipment. In this section, we discuss the situation when the grid must be upgraded to accommodate one customer.[31]

For the reasons discussed in the previous section, correct financial incentives generally do not exist to induce the utility to install DG as an alternative to a line extension. As we stated in that section, we do not recommend changing current policies at this time to address that problem and we do not recommend prohibiting utilities from involvement with DG for this purpose.

However, correct financial incentives generally do exist for the *customer* to install DG in this instance. Under current policy, when a line extension is built or upgraded, the customer pays the cost in part or in full. When the customer pays the full cost, the customer may accurately compare the economics of DG with on-grid generation.[32] However, when the customer does not pay the full cost, the customer cannot compare DG with on-grid generation accurately, and DG is artificially discouraged. In particular, residential and smaller business customers in most service territories receive some portion of a line extension at no cost, and may pay less than full cost for the remainder of the extension.[33]

In our view, line extension policies that allow a customer to receive extensions at less than full cost do not send appropriate price signals to the customer. We believe it is not yet critical to address this problem, because DG alternatives for

[31] Two situations exist -- the utility may build a line extension to a single customer or the utility may upgrade the grid "upstream" to accommodate a single customer's growth. The second situation is more problematic than the first, and is being investigated by the Commission.

[32] In CMP's territory, customers pay the full cost of a line extension.

[33] The Commission's report to the legislature in December 1999, summarized line extension payment approaches for CMP, BHE, and MPS.

smaller customers are still too costly for widespread adoption. However, in the longer term, this inequity should be eliminated.[34]

We have determined that, in the near term, utilities should examine their line extension policies – in particular, those for larger customers -- to determine if customers should pay the full amount of a line extension, but they should not be required to adopt such changes. As fuel cells, photovoltaics, and microturbines mature, the Commission will re-consider whether the line extension polices of all utilities in the state should be fully cost-based.

VIII. UTILITY OR AFFILIATE OWNERSHIP OF DG

An issue distinct from whether utilities should own or control DG for purpose of T&D system efficiency is whether utilities or their affiliates should own or control DG on the customer side of the meter for purposes of providing electric supply. The Interim Report discusses the potential benefits and detriments of allowing utilities or affiliates to be in the competitive DG business (page 25). The primary benefits are the possible mitigation of lost utility revenues that would occur from DG installations, the addition of sophisticated participants in the DG market, increased likelihood that DG would be installed in a manner beneficial to the grid, and the elimination of an incentive for utilities to impede DG deployment. Major detriments are the partial loss of the separation of the T&D and generation functions (which is a core feature of industry restructuring), the possible exercise of utility market power or other actions that could reduce DG competition, and the corresponding need for greater regulatory oversight.

In our view, policy makers should be concerned that utilities, by virtue of their status as monopoly suppliers of T&D services, have unique opportunities to favor their DG activities or their DG affiliate over other DG competitors. We believe that the safeguards inherent in Maine's current restructuring law and in Chapter 820 of the Commission's rules have been a necessary and reasonable response to these types of concerns as they relate to generation activity of all types.

In considering whether utilities should be allowed to engage directly in DG activity, we note that DG as an electricity supply is a competitive business that is not a regulated core utility activity. Chapter 820 requires that unregulated utility business activities be conducted through separate corporate subsidiaries to protect ratepayers from the financial consequences of the non-utility activities. The financial risks and benefits of the unregulated activities are borne by utility shareholders; ratepayers are insulated from the impact of such activities to the largest degree possible. We see no

[34] A more difficult question is the extent to which costs of upgrades upstream in the distribution system (e.g., a substation upgrade), that are required for a single customer's load growth, should be funded by the customer. To the extent that costs are shared between customer and utility, neither can accurately compare the cost of DG with the cost of on-grid power.

reason to deviate from this basic principle when considering utility participation in DG. Thus, we conclude that utilities should continue to be prohibited from engaging directly in DG activity for the purpose of electrical supply, although we recognize that, as a result, ratepayers would not benefit from utility revenue loss mitigation (if any) that is one potential advantage of allowing utilities to enter the DG market.

The next issue is whether utilities should be allowed to enter the competitive DG business through a separate affiliate. Confining ownership to an affiliate eliminates some risks and some benefits attained through direct utility ownership. Maine's Restructuring Act provides that T&D utilities "may not own, have a financial interest in or otherwise control generation or generation-related assets."[35] This provision appears to prohibit a direct utility subsidiary from engaging in DG business activities.[36] Regardless of the current law, there are conflicting policy considerations in determining whether utility affiliates should be allowed to enter the DG business. The Restructuring Act prohibits utilities from owning or controlling generation *assets*. However, the Restructuring Act allows utilities to *market* generation services through an affiliate subject to strict standard of conduct.[37]

The DG business is similar and complimentary to generation service marketing, and thus it may be reasonable to treat them in a similar manner. Increased regulatory oversight could carefully maintain the safeguards embodied in the Commissions' standards of conduct. We also recognize that utilities might be more accepting of the market if their shareholders stand to benefit from DG implementation and that DG deployment might occur more quickly. However, in our view, utility affiliates are no better suited than other industry participants to develop an efficient DG market.[38] On the contrary, we have serious concerns regarding potential market abuse when one player has access to critical market information that is unavailable to all players or is in a position to impede the activities of its affiliate's competitors. In addition, we have serious concerns regarding the incentive for a utility to refrain from offering a price discount to retain a customer with a DG option and install the DG option through its own affiliate. The consequence would be additional loss of the customer's contribution to fixed utility costs, increased pressure on other ratepayers' prices and the possible installation of DG that is less efficient than on-grid power.

[35] 35-A M.R.S.A. § 3204(5).

[36] It is less clear to what extent this provision prohibits the parent company of a utility or a relatively distant utility affiliate from owning or having an interest in DG. CMP and BHE either are or will be owned by holding companies that have affiliates that own generation. The issue of the applicability of 35-A M.R.S.A. § 3204(5) in these instances has not been litigated.

[37] 35-A M.R.S.A. §§ 3205, 3206, 3206-A. These provisions limit the market share of CMP and BHE affiliates in their respective territories to 33% and appear to prohibit affiliate marketing after 10% or more of the stock of the utility is purchased by an entity.

[38] Only one Maine utility currently retains a marketing affiliate.

After balancing the benefits of either course of action, we conclude that the benefits attained by utility affiliate ownership of DG are outweighed by the risks to other utility ratepayers and market participants. Thus, we recommend that no change be made to the restructuring law, and that utilities and their affiliates continue to be prohibited from owning or having a financial interest in DG other than for T&D system support.

IX. POLICY ISSUES

A basic question for policy makers is whether Maine should adopt new laws or regulations that actively encourage or discourage DG, or allow DG to develop over the next several years based on the current state of the law. Many of the issues underlying these policy questions are broad electricity (and natural gas) policy questions that are generally outside of the Commission's basic function.

Still, we are aware of the broader policy issues. DG offers a number of potential advantages, many of which we have already touched upon in this report. The primary advantages are:

- DG provides another source of generation for the competitive regional generation market. These new DG resources are a new source of supply and/or customer alternatives to buying electricity from the regional market, particularly during high cost periods. It is in everyone's interest to help ensure vigorous competition for electric energy and capacity.
- DG done by utilities provides another tool for planning and investing in the local electric transmission and distribution system, which should reduce system costs.
- DG may encourage expansion of the local gas distribution system. Maine has three Local Gas Distribution Companies (LDC's). In considering new local system expansions, each compares the cost of the expansion with the revenues that will be generated by the expansion. Gas-fired DG units could produce additional revenues on new lines, thereby making LDC expansion more viable.
- DG has the potential to place competitive pressure on the electric distribution utilities. If the cost of distribution becomes too high, customers will tend to opt increasingly for DG installations. As a result, distribution utilities will have a strong incentive to control their costs, or at least the rates that they charge customers for whom DG is a viable alternative.
- Expanded DG could increase fuel diversity if DG that is not fired by natural gas or oil becomes economically viable. Greater fuel diversity is advantageous because it reduces the impact of supply disruptions and price increases by a single fuel source.

There are other issues to consider as well. One about which it is difficult to generalize is the environmental impact of DG. Environmental impacts vary from case to case depending on the DG installation and the environmental impacts of the resources that DG will displace. Some DG sources – wind, hydro and solar -- have no emissions.

(They could, of course, have other environmental and/or land use implications). Others, notably diesel- and gasoline-fueled reciprocating engines may have substantial emissions. A policy that intends to use DG as a method of dealing with environmental issues would need to distinguish among the various forms of DG.

Another issue is the impact of DG on the incumbent T&D utilities. To the extent that DG reduces the throughput on the distribution system, it will reduce the utility's revenues and, particularly in the short run, its profits. This could create a new round of stranded costs which many stakeholders understandably wish to avoid. Over a longer time horizon, however, this problem might be reduced or eliminated. When a new DG facility comes on line, it is not likely to reduce the utility's costs immediately. However, over time, DG creates savings for the utility to the extent it avoids new investments in the distribution system. This is most obvious where the DG facility is specifically targeted to constrained areas of the T&D system, but could also occur in other portions of the utility system over time. Conversely, DG facilities have the potential to increase the cost of operating the distribution system or to create the need for investment in the system. This conflict between the immediate impact of DG and the longer-term savings or costs will require ongoing oversight by the Commission.

The issues involving DG generally involve broad energy policy considerations. The Commission will assist the Legislature in any manner that would be useful as it considers matters related to DG.

Appendix A

Summary of Distributed Generation Technologies and Characteristics Developed by Resource Dynamics, Inc. and Presented in "Assessment of Distributed Generation Technology Applications"

		Size Range (kW)	Efficiency (%) Electric	Efficiency (%) Overall	Emissions (g/kWh unless otherwise noted)	Packaged Cost ($/kW)[1]	Installation Cost ($/kW)[2]	Electric-Only Cost-to-Generate (cents/kWh)[3]	Cogeneration Cost-to-Generate (cents/kWh)[4]	Applications Cont.	CHP	Peak	Green	Prem.
Reciprocating Engines														
Spark Ignition		30-5,000	31-42	80-89	NO_x: 0.7-42 CO: 0.8-27	300-700	150-600	7.6-13.0	6.1-10.7	●	◒	●	○	◒
Diesel		30-5,000	26-43	85-90	NO_x: 6-22 CO: 1-8	200-700	150-600	7.1-14.2	5.6-10.8	●	◒	●	○	◒
Dual Fuel		100-5,000	37-42	80-85	NO_x: 2-12 CO: 2-7	250-550	150-450	7.4-10.7	6.0-9.1	●	◒	●	○	◒
Turbines														
Microturbines	Non-Recup.		14-20	75-85		700-1,000		14.9-22.5	10.1-15.9	○	●	◒	○	◒
	Recup.	30-200	20-30	60-75	NO_x: 9-125ppm CO: 9-125ppm	900-1,300	250-600	11.9-18.9	10.0-16.8	◒	◒	◒	○	◒
Industrial Turbines		1,000-5,000	20-40	70-95	NO_x: 25-200ppm CO: 7-200ppm	200-850	150-250	8.7-15.8	5.8-12.2	◒	●	◒	○	◒
Fuel Cells														
PEM		5-10	36-50	50-75	NO_x: 0.007 CO: 0.01	4,000-5,000	400-1,000	21.9-33.3	20.7-33.3	●	○	○	●	●
Phosphoric Acid		200	40	84	NO_x: 0.007 CO: 0.01	3,000-4,000	360	18.6-22.8	17.0-21.2	●	●	○	●	●
Renewable														
Photovoltaic		5-5,000	-	-	-	5,000-10,000	150-300	18.0-36.3	N/A	◒	○	○	●	○
Wind		5-1,000	-	-	-	1,000-3,600	500-4,000	6.2-28.5	N/A	○	○	○	●	○

[1] Packaged costs include the prime mover, generator, inverter (if needed), and ancillary equipment. Costs can vary based on size, duty cycle, and fuel.

[2] Installation costs can vary with utility interconnection requirements, labor rates, ease of installation, and other site-specific factors.

[3] Cost-to-Generate assuming a 50% load factor and 1999 Maine average price of natural gas to the commercial sector and no thermal utilization. Cost-to-generate includes fuel and O&M expenses as well as amortized capital charges.

[4] Cost-to-Generate assuming a 50% load factor and 1999 Maine average price of natural gas to the commercial sector, 75% utilization of thermal output, and cogeneration equipment adder of $100/kW for reciprocating engines, $150/kW for turbines, and $75/kW for fuel cells. Cost-to-generate includes fuel and O&M expenses as well as amortized capital charges.

Key:
- ● Good fit
- ◒ Moderate fit
- ○ Poor Fit

Applications

Cont. = Continuous Power
CHP = Combined Heat and Power
Peak = Peaking Power
Green = Green Power
Prem. = Premium Power